NATIONAL ENERGY TECHNOLOGY LABORATORY

Existing Plants, Emissions and Capture – Setting CO_2 Program Goals

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Table of Contents

III. REALIZING EPEC PROGRAM R&D GOALS 10

List of Figures

List of Tables

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EXECUTIVE SUMMARY

Electric power plants are major contributors to carbon dioxide (CO_2) emissions in the United States. If in the near future, the United States is to make significant reductions in greenhouse gas (GHG) emissions; CO_2 emitted by these plants will need to be reduced. One approach for achieving major reductions is through carbon capture and storage (CCS). However, system analyses have shown that current technologies for CO_2 recovery and compression from flue gas impose a severe economic penalty on the cost of electricity (COE) generation that could increase COE by 85 percent or more. This report establishes research and development (R&D) performance and cost goals for CO_2 capture applicable to *new and existing* coal-fired power plant technologies of:

Minimum CO_2 Captured = 90%

Maximum Increase in COE = 35%

The goals presented in this report are intended for use in measuring the progress of post-combustion CCS technology development under the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) Existing Plants Emissions and Capture (EPEC) R&D Program. CCS technologies applicable to new and existing pulverized coal (PC) power plants include post-combustion capture technologies, such as absorption, adsorption, membrane separation, oxy-combustion, and chemical looping, for directly producing a concentrated CO_2 stream for sequestration.

The NETL EPEC R&D Program goals are not meant to establish possible future policy or regulations, because R&D success cannot be guaranteed; nor are they intended to be generically applied to determine the economic feasibility of a real world retrofit to an existing PC power plant. Some power plants will be better equipped to take advantage of new technologies than others, and some plants may be re-powered, rebuilt, or retired. However, it is prudent to aggressively develop and deploy technologies that will allow many of these existing plants to remain in operation until longer term solutions for reducing GHG emissions can be developed, tested, and implemented.

The above goals are feasible, but aggressive, and may be achievable through a focused R&D program directed toward:

1) Lowering the direct capital and operating costs of in-plant CCS technology.
2) Improving the efficiency of CCS technology to minimize any de-rating of PC power plants fitted with this technology.
3) Lowering the costs associated with retrofitting existing PC plants with CCS.
4) Increasing onsite steam and power generation to offset CCS parasitic power requirements.

This report provides strategies for addressing these four objectives and achieving the EPEC program cost and performance goals. Further assessment will be required to quantify potential cost and performance benefits, and to identify new R&D opportunities.

COMMON ACRONYMS/ABBREVIATIONS

Acronym/Abbreviation	Definition
BACT	Best Available Control Technology
CCS	Carbon/CO_2 Capture & Storage
CF	Capacity Factor
CO_2	Carbon Dioxide
COE	Cost of Electricity
DOE	U.S. Department of Energy
EPEC	Existing Plants Emissions and Capture
EPRI	Electric Power Research Institute
GHG	Greenhouse Gas
Hg	Mercury
HHV	Higher Heating Value
IGCC	Integrated Gasification Combined Cycle
LCOE	Levelized Cost of Electricity
LNB	Low-Nitrogen Oxides Burner
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NOx	Nitrogen Oxides
OFA	Over-Fire Air
PC	Pulverized Coal
PM	Particulate Matter
R&D	Research and Development
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SOTA	State of the Art
TPC	Total Plant Cost
TSM	Transport, Storage, and Monitoring

I. INTRODUCTION

Electric power plants are major contributors to carbon dioxide (CO_2) emissions in the United States. If in the near future significant reductions in greenhouse gas (GHG) emissions are mandated, the CO_2 emitted by these plants will need to be reduced. One approach for achieving major reductions is through carbon capture and storage (CCS).[a] However, system analyses have shown that scale up of current scrubbing technologies for CO_2 recovery and compression for flue gas applications imposes a severe economic penalty on the cost of electricity (COE) generation. This penalty could increase COE by 85 percent or more. This report establishes research and development (R&D) goals for CO_2 capture applicable to *new and existing* coal-fired power plant technologies. These goals are intended for use in guiding DOE-sponsored CO_2 capture R&D under the National Energy Technology Laboratory's (NETL) Existing Plants Emissions and Capture (EPEC) Program and for assessing the progress of any such R&D efforts.

There are some 1,100 boiler furnaces operating at the 460 coal-fired power plants generating electricity within the United States [1]. Pulverized coal (PC) plants are widely distributed across the country, and vary considerably by age, footprint, coal type, and environmental controls. These factors will impact the cost and performance of CO_2 capture technologies deployed across the existing PC fleet. Some PC plants will be better equipped to take advantage of new technologies than others, and some plants may be re-powered, rebuilt, or retired. However, so that power demand can be adequately satisfied as carbon constraints are implemented, it is prudent to aggressively develop and deploy technologies that will allow many of these plants to remain in operation until longer term solutions for reducing GHG emissions can be developed, tested, and implemented. This is especially true for newer plants that are not near the end of their useful life.[b]

The U.S. Department of Energy's (DOE) NETL has completed engineering system analyses for *new* grassroots PC and Integrated Gasification Combined Cycle (IGCC) power plants [2]. Cost and performance R&D goals for pre-combustion CO_2 capture technologies applicable to IGCC power plants have been established by NETL's Carbon Sequestration Program. The objective of this report is to outline similar goals for EPEC Program R&D relevant to PC power plants. The goals for PC power plants are not identical to those for IGCC plants because PC plant technology is already extensively deployed in the United States and IGCC technology is still in the early stages of commercialization. CCS technologies applicable to PC plants include post-combustion capture, such as absorption, adsorption, membrane

[a] A more comprehensive definition of CCS would be: CO_2 Capture + CO_2 Compression + CO_2 Transport + CO_2 Storage + CO_2 Monitoring

[b] Newer existing power plants have a high base cost of electricity relative to older plants; for which, the initial capital investment may be nearly paid off. For example, in a recent NETL study [3], the COE for the *existing* Conesville Unit #5 was determined to range from 2-2.5¢/kWh, compared to 6-7¢/kWh for a *new* subcritical or supercritical power plant. The higher cost of the new plant primarily reflects the amortization of the initial capital investment, and this investment will be lost if the plant is shuttered. Therefore, mothballing a newer plant results in an inefficient use of financial capital. The inefficient use of capital should be avoided when considering carbon mitigation strategies, since it will result in either a higher overall cost of mitigation or a reduction in the total amount of carbon mitigated.

separation, oxy-combustion, and chemical looping technologies for directly producing a concentrated CO_2 stream for sequestration.

The EPEC R&D goals include two components: (1) a performance criterion related to the quantity of CO_2 captured, and (2) an economic criterion related to the total cost incurred due to capture. For establishing a quantitative performance goal, 'Percent CO_2 Captured' is used, and defined as:

$$\boxed{\%CO_2\ Captured = 1 - \left(\frac{Carbon_{StackGas}}{Carbon_{Coal} + Carbon_{Air}} \right) \times 100} \qquad (1)$$

The economic criterion used to specify a numerical goal is 'Percent Increase in COE' due to the addition of CO_2 capture[c], and defined as:

$$\boxed{\%\ Increase\ \ in\ COE = \left(\frac{COE_{Capture} - COE_{NoCapture}}{COE_{NoCapture}} \right) \times 100} \qquad (2)$$

These criteria are consistent with previously established DOE goals for other CCS Program R&D areas, and possess desirable characteristics:

1) They can be related back to system parameters that are commonly reported by the power industry and are relatively easy to estimate.
2) They are insensitive to the size of the power plant. While they have a specific basis related to power plant output, they are expressed in terms of percentages.
3) They are dimensionless and can be easily understood by both technologists and the general public alike.

There are several other metrics in addition to Percent Increase in COE that could be and are used when evaluating the economics of a CO_2 capture technologies. These are 'Incremental COE,' 'Cost per Ton of CO_2 Captured,' and 'Cost per Ton of CO_2 Avoided.' These are described in Appendix A of this report, and may be more applicable in other non-R&D related assessments.

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[c]When comparing the impact of installing CO_2 capture technology on existing power plants, it is important to remember that *the base COE for most existing plants will be much lower than that for a new PC power plant*. Even if the incremental cost of CCS on an absolute basis were the same between a new and existing power plant, the percent increase in COE would not be equal.

II. EPEC R&D PROGRAM GOALS

For assessing long-term, EPEC-sponsored R&D, numerical goals for CO_2 capture technologies, compatible with *existing* coal-fired power plant systems, are established as:

Minimum CO_2 Captured = 90%
Maximum Increase in COE = 35%

The selection of a minimum 90 percent CO_2 capture goal is based on a number of considerations. First, it is important to note that current state-of-the-art (SOTA) acid-gas scrubbing technologies are capable of removing approximately 90 percent of the CO_2 contained in a typical flue gas stream[d]. Although greater than 90 percent capture might be theoretically achievable for some advanced technologies, it is unlikely to be cost-effective due to process limitations and diminishing returns. A 90 percent capture goal also maintains consistency with the NETL Carbon Sequestration Program R&D goal for CO_2 capture already established for new IGCC power plants. Furthermore, a 90 percent capture goal is supported by the extensive "wedge" analyses conducted by Princeton, NETL, Electric Power Research Institute (EPRI), and others [4-6]. These studies found that a minimum of 90 percent CO_2 reduction from fossil fuel power plants is required to make a significant impact on stabilizing atmospheric CO_2 levels. Although NETL has established a 90 percent capture goal, there are circumstances when it may be desirable to assess the impact of CO_2 capture at less than 90 percent removal, and certain capture technologies may have limitations on the amount of CO_2 that can be captured. These situations should be assessed separately on a case-by-case basis.

NETL selected a maximum increase in COE of 35 percent for the cost goal based on assuming an aggressive, yet practical, performance improvement of advanced CO_2 capture technologies compared to current SOTA. NETL studies indicate that amine-based scrubbing, which is considered the current SOTA CO_2 capture technology for PC power plants, results in approximately an 85 percent increase in COE. Conversely, as described later in this report, a thermodynamic analysis of CO_2 capture from the combustion flue gas of a PC power plant indicates the theoretical minimum energy requirements for 90 percent separation and compression would result in approximately a 15 percent increase in COE. Recognizing that achieving theoretical minimum energy requirements would be impractical, NETL selected a maximum 35 percent increase in COE as an aggressive, yet practical, cost goal.

The maximum increase in COE of 35 percent is relative to the COE of a base PC plant without capture that is chosen be the platform for all proposed PC CCS installations. In order to establish a valid basis for comparison, each CCS technology will be compared as it would be applied to a consistent, yet conceptual plant design. NETL completed an analysis published in a report, titled, "Cost and Performance Baseline for Fossil Energy Plants," [2] that established SOTA (*circa.* 2005-06) power generation technologies both with and without carbon capture. This report included a baseline design, operation, and economics for a

[d]This level of removal using existing technology is achieved on a smaller scale in urea and food-grade CO_2 production [7].

subcritical PC power plant, which is considered to be the baseline for comparison of CCS technologies evaluated by the EPEC Program. The baseline COE for this plant is 64.0 mills/kWh.

Establishing a consistent, unbiased baseline for comparison allows NETL to evaluate CCS technologies without the influence of the eccentricities of existing power plants that might otherwise be selected as the baseline; incorporating certain CCS technologies in unique plant configurations, locations, etc., may result in more attractive, niche-type applications than might be the case if the same technology was proposed as a fleet-wide solution to reduce CO_2 emissions.

In addition, it was decided to conceptually apply any proposed CCS technology to a plant that would result in the *same net power output* as the baseline power plant without CCS. Typically, when CCS technology is implemented, a significant auxiliary load is required to perform CCS. This means that the existing electric grid will lose power generation capacity. It is difficult to quantify the effect of this lost power because there are so many options to replenish this power. Because this is so difficult (and fortunately is not required to adequately compare one CCS technology to another), deciding on how to replenish any lost power due to CCS implementation is outside the scope of EPEC goal development. The primary purpose of this report is to explain and justify the EPEC goals for CCS R&D, and compare the technical and economic performance of different CCS technologies against these goals. For the purposes of evaluating CCS technologies against the EPEC goals, all CCS technologies will be compared as installed on a plant with a net 550-MW capacity, relative to a baseline plant without capture that also has a net 550-MW capacity. Essentially, this evaluation process demands that all CCS technologies make up power in the same way – by increasing plant size. While it is a theoretical construct, this process allows the CCS evaluation to avoid the cost consideration of the many ways to make up the lost power to the grid.

The COE numerical goal given above is aggressive, reflecting the longer-term, higher-risk nature of DOE's EPEC R&D Program. The goal is based on *achieving an increase in COE equivalent to or less than the current direct costs of SOTA systems alone* (as depicted in Figure 1). Further analysis, outside the scope of this report, is required to relate the COE goal to the overall economic consequences of stabilizing atmospheric CO_2 levels.

A. R&D Goal Diagram

Figure 1 assesses long-term, EPEC-sponsored R&D by plotting *direct costs* versus *indirect costs* for CCS when applied to new and existing power plants. The total cost for a plant retrofit is the sum of these two cost terms. Direct costs are the capital and operating costs associated with the capture, transport, and sequestration of the CO_2 produced by the plant prior to the retrofit. Costs associated with the modification of existing processes at the plant are not considered as direct costs. The cost of modifications is included in the indirect cost term, *along with any other costs associated with de-rating the power plant*. Any power or steam required to operate the CCS system results in an added parasitic load to the existing plant and lowers the plant power generating efficiency. This electric power loss must be made-up through other modifications to the existing plant or by supplying power from some other outside source. Table 1 summarizes the distinction made between direct and indirect costs.

Marked on Figure 1 is point A, which is for a SOTA, amine-based capture system, and corresponds to a *new* PC plant. The *x* and *y* coordinates of point A are computed from the costs for a SOTA plant with and without CO_2 capture. The basis for the numerical values plotted in Figure 1 is discussed in the following section.

The red diagonal line in Figure 1 represents the costs at which incorporating CCS results in exactly a 35 percent increase over COE of a new PC plant without CCS; this 35 percent increase is the NETL EPEC goal for CCS. Any CCS system with direct and indirect costs that fall to the left of this line will surpass the goal. Currently, all proposed CCS technologies fall to the right of the red line. The vertical, dashed, red line is an approximation of the cost due to the minimum theoretical parasitic load for CCS (also referred to here as "minimum work"). In theory, no process can be made efficient enough to fall to the left of this line. The determination of this line is based on a "second-law" analysis and is detailed in Appendix D.

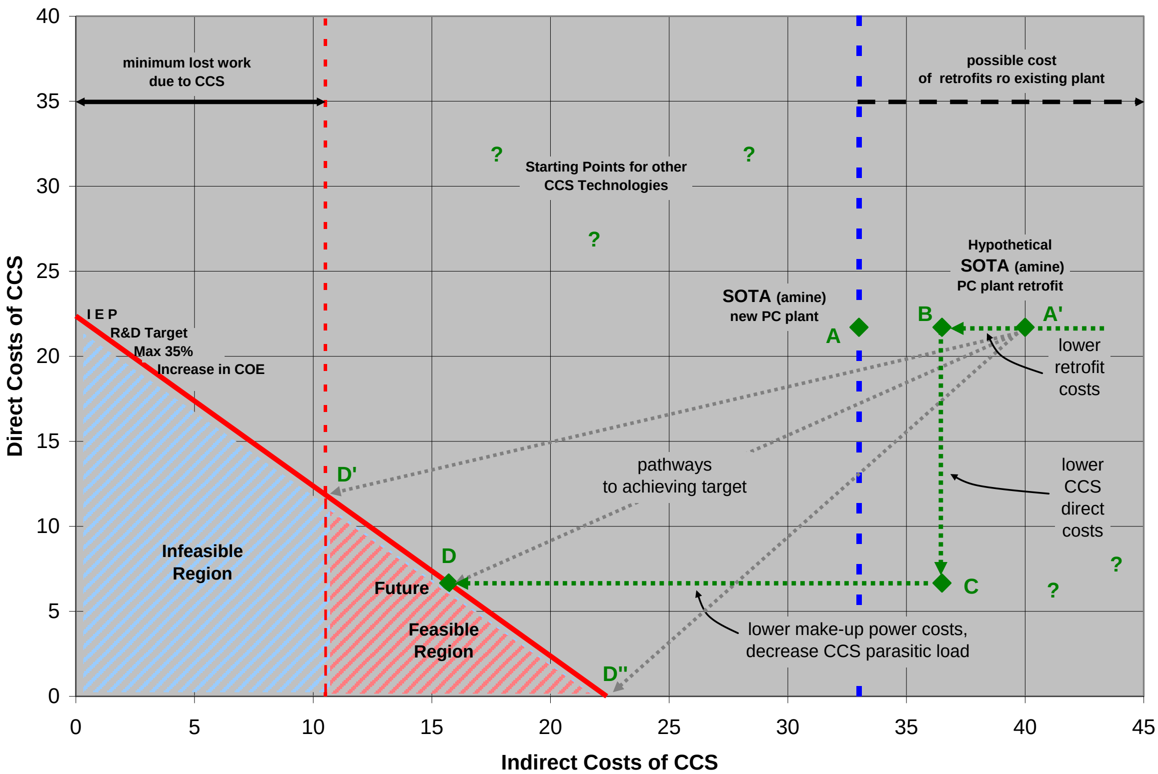

Figure 1: Goal Diagram for EPEC CCS *Incremental Mills/kWh*

Table 1: Direct and Indirect Costs of CCS

Direct Cost	Indirect Cost
Includes Capital + Operating Cost for 90% CO_2 capture from when added to a new PC plant.	**Includes** cost associated with modification of existing power plant equipment to accommodate the installation of the new CO_2 capture unit.
Excludes incremental capital and operating costs due to CO_2 capture energy use (or parasitic load). This would derive from over sizing a new PC power plant or 're-powering' an existing unit to provide steam and/or auxiliary power to run the CO_2 capture process.	**Includes** 'energy penalty' cost—also referred to as CO_2 'make-up power' cost, 'parasitic load' cost, 'auxiliary load' cost. This is the cost associated with "over sizing" a new PC power plant to provide steam and/or power for the integrated CO_2 capture unit to overcome auxiliary load increases and maintain 550MW net output.
Excludes 'make-up' power cost. Does not include cost from 'purchasing power' or 'revenue lost' cost due to a reduction in net power output.	

All retrofits of an existing PC plant will fall along a horizontal line through and to the right of the dotted line passing through Point A (*new PC plant*). For illustration, Point A' represents a possible retrofit to an existing plant. One possible pathway for achieving the EPEC goal starting from Point A' is shown by the dashed green line. The goal is met by a combination of reductions in capital and operating costs of CCS, retrofit costs, and make-up power costs. Make-up power costs may be reduced by either decreasing the CCS parasitic power requirements (i.e., by improving the efficiency of the CCS process), or by providing a cheaper source of make-up power.

A number of important observations, relevant to EPEC R&D Program planning, can be related back to the goal diagram:

1) At least for the SOTA amine-based system, the indirect costs (retrofit and energy penalty) well exceed the direct costs (capital and operating) of CCS. This is especially true if realistic retrofit costs are included, which can increase the capital costs by a factor of 1.2 to 1.5[4]. This implies that R&D should be focused more on increasing the energy efficiency of absorption technologies and minimizing the cost of retrofitting for existing plants than on decreasing direct CCS capital and operating costs.

2) However, the capital cost of the SOTA amine-based technology cannot be ignored in any R&D effort, since judging from the estimated theoretical minimum work required for CCS (red dashed line), a feasible goal can only be achieved by at least a 45 percent reduction in direct costs (Point D' in Figure 1). Therefore, improvements in both capture efficiency and capital and operating cost reductions will be needed. Multiple cost reduction pathways are possible for achieving the goal (as illustrated in Figure 1 by the dashed arrows between Point A' and the line segment connecting Points D' and D''). Tradeoffs between direct and indirect costs must be carefully examined and considered in parallel in any R&D effort. Hybrid processes may combine the best of two or more processes in order to simultaneously lower both direct and indirect costs.

3) While the cost of retrofitting an existing plant is uncertain, and was not considered in developing the COE goal, major cost reductions for retrofitting will in all likelihood be needed. Further assessment will be required to quantify these costs, and novel

approaches and technologies for retrofits should be a major area within the EPEC R&D Program[e].

4) Various other CCS technology platforms, such as membranes, adsorption, cryogenic fractionation, etc. (illustrated by the points labeled with '?' in Figure 1), will exhibit different distributions for direct and indirect costs. If the make-up power cost is high, then the direct capital and operating costs will need to be low, and vice versa (analogous to the tradeoff that often exists between capital and operating costs in most industrial processes). In addition, some technologies may be more applicable to a retrofit of an existing PC plant. Further assessments are needed in order to quantify the benefits and drawbacks of other CO_2 capture and pressurization technologies.

5) Finally, the potential for achieving the EPEC COE goal can be significantly improved if technologies for reducing the make-up power requirement, by providing supplemental onsite generation, are also considered in future R&D projects. Increased retrofit costs for these options may be more than offset by lower make-up power costs.

B. CCS Cost Basis

In 2007, NETL completed an extensive systems analysis of current SOTA fossil energy-based power plants that included PC power plants [2]. Table 2 lists the COE breakdown for a new subcritical PC power plant without CCS (Reference Plant) and the incremental COE for the same plant designed with CO_2 capture.

The total COE of the reference power plant is 64 mills/kWh, and the incremental COE for the same plant with CCS is 55 mills/kWh. These costs are allocated to five categories: capital; fuel; fixed and variable operating expenses (excluding fuel); and CO_2 transport, storage, and monitoring (TSM).

Table 2: Cost Breakdown for CO_2 Capture & Sequestration

Cost of Electricity →		No Capture (mills/kWh)	CO_2 Capture (mills/kWh)	Incremental (mills/kWh)
Capital		34.1	68.0	33.9
Operating	Fixed Operating	3.8	5.8	2.0
	Variable Operating	5.8	10.8	5.0
Fuel		20.2	29.8	9.6
Transport, Storage & Monitoring		0	4.3	4.3
Total (mills/kWh)		**64.0**	**118.8**	**54.8**
Percent Increase in COE			**86.0%**	

[e] For a grassroots plant engineered and designed for CCS, the retrofit costs would be zero. Ideally, the cost of the retrofit would be small, on the order of 20% or less of the capital cost of the CCS. It would include incidental costs associated with installing the CCS on the existing plant, such as wiring and rerouting piping and tie-ins, plant layout modifications, etc. In reality, retrofitting costs are likely to be quite large, 50% of the CCS capital or possibly much more, due to modifications to the existing boiler and steam turbine, which would be necessary if the CCS system consumes large quantities of steam. The make-up power costs, however, are the same for a plant retrofitted with CCS and a new plant of the same capacity employing the same CCS technology. The difference between the two is that for the retrofit, the make-up power is supplied to the grid by some unidentified source outside the plant fence; whereas, the new plant is oversized in order to supply the power deficit caused by the operation of the CCS systems.

From Table 2, it appears that capital cost is the largest contribution to incremental COE. This, however, is misleading, since CO_2 capture and compression consumes a large amount of power (directly as electricity and indirectly as steam consumption). Due to this parasitic power requirement, the gross size of the PC plant fitted with CCS must be larger than the reference plant to maintain the same net electricity output (550 MW). Increased plant capacity is needed to provide the electricity (included in auxiliary power) and low-pressure steam (extracted from the steam turbine) required for CO_2 capture and compression[f]. The capital cost increase (33.9 mills/kWh) given in Table 2 in includes, but does not explicitly break out, this energy-related capital cost of CCS due to increased plant capacity (i.e., larger boiler, larger steam turbine, etc.) required to "make-up" power. This same argument applies to fixed (*e.g.*, increased maintenance requirements) and variable (*e.g.*, increased non-fuel consumables) operating costs, and fuel cost (increased coal consumption).

Allocation of the increase in COE to the components that make up the CCS system should accurately reflect the true causes of the increase. Such an allocation is valuable for establishing a realistic COE goal and for strategic program R&D planning to identify the most effective technologies and projects. Specifically, the increase in COE can be broken down into the four major categories to better reflect the true component costs:

1) Capital and operating costs directly associated with in-plant CO_2 capture and compression (within purview of EPEC Program).
2) Capital and operating costs directly associated with CO_2 transportation, storage and monitoring (outside purview of EPEC Program but within the Carbon Sequestration Program).
3) Indirect capital and operating costs associated with retrofitting the existing plant to accept the CCS system.
4) Indirect costs of make-up power associated with de-rating the existing plant.

The first two items above are directly associated with the addition and operation of the CCS systems for the retrofitted plant. The last two items are indirect consequences of adding CCS systems to this plant. Item 4 specifically includes the effects of increasing overall plant size to maintain a constant net power output after CCS has been incorporated. This is considered to be an indirect cost because, while it is not a direct result of adding CCS equipment, the fact that CCS equipment is required means that the plant auxiliary load will increase and the total size will then need to increase to maintain net output. A portion of the total capital cost increase in Table 2 caused by de-rating the plant was assigned to the category called "Make-Up Power" by determining how much the overall plant size, and thus cost, increased due to the reduction in plant efficiency (See Appendix C). It is important, even if only conceptually, to compare the effect of CCS technologies on plants of equivalent net power output so that an unbiased basis for comparison can be established for all proposed CCS technologies. Doing so also eliminates the need to consider the cost of making up the lost power to the grid, which can become very complex due to the numerous possibilities available. Table 3 gives these redistributed costs associated with CCS.

[f] The bulk of the electricity is used in compression and the steam in the amine regeneration step.

Notice that the direct capital cost increment, that cost due only to installing CCS, is actually 12.6 mills/kWh while the total capital cost increment, including the effects of making the entire plant larger, is 33.9 mills/kWh (Table 2). It is the total CCS direct costs in Table 3, 21.7 mills/kWh, and total CCS indirect costs, 33.1 mills/kWh that are plotted as the coordinates of point A in Figure 1. The EPEC COE goal is based on achieving a 35 percent increase in COE, which equates to no more than 22.4 mills/kWh being added to the base plant without capture (64.0 mills/kWh).

Table 3: Redistributed CO_2 Capture & Sequestration Costs

CCS Specific Costs	Incremental COE (mills/kWh)	Percent of Total
CO_2 Capture Direct Capital	12.6	23.0%
CO_2 Compression Direct Capital	1.4	2.6%
Direct Fixed Operating	1.4	2.6%
Direct Variable Operating	3.4	6.2%
Total In-Plant Direct	**18.8**	**34.3%**
Total CO_2 TSM Direct	**2.9**	**5.3%**
TOTAL CCS Direct Costs	**21.7**	**39.6%**
Total Retrofit*	**-**	**-**
Make-Up Power	**33.1**	**60.4%**
TOTAL CCS Indirect Costs	**33.1**	**60.4%**
TOTAL CCS Costs	**54.8**	**100%**

*Retrofit costs will vary based on CCS technology deployed and plant specific factors and so are not factored into the technical evaluation of COE increase.

III. REALIZING EPEC PROGRAM R&D GOALS

The Cost Goal Diagram discussed in Section II, suggests a number of approaches for lowering the cost of CCS for existing plants. Table 4 lists EPEC R&D Program objectives that should be considered moving forward, and also provides strategies for achieving these objectives, with examples of technology-based solutions to consider.

Table 4: Objectives for EPEC Program Sponsored R&D

Strategy	Examples
OBJECTIVE 1 – Lower Specific Capital Costs of CCS	
Improve CCS Process Technologies	Advanced absorption, adsorption, membrane, cryogenic, oxy-combustion, chemical looping or hybrid technologies
Develop Alternative Materials of Construction	Use less and substitute lower cost materials
Process Intensification	Combine absorption/desorption in single vessel; Combine capture & compression/liquefaction
Reduce Equipment Volumes	Use oxygen-enriched combustion air to reduce flue gas volumetric flow & increase flue gas CO_2 concentrations (improved driving force)
OBJECTIVE 2 – Lower Specific Operating Costs of CCS	
Improve Solvents, Solid Sorbents, Membranes, etc.	Lower materials & manufacturing costs and improve operating life
Improve CCS Operability & Reliability	Develop & design for minimum maintenance, *e.g.*, gas separation membranes
OBJECTIVE 3 – Improve Energy Efficiency of CCS	
Reduce Sorbent/Solvent Regeneration Energy	New or improved solvents, solid sorbents
Reduce CO_2 Capture Requirement	Supplement coal with alt. fuels such as natural gas, biomass, wastes (lowers fossil carbon footprint) Use CO_2 for algal aquaculture to produce supplemental fuel on site
Process Intensification & System Integration	Combine unit operations to improve driving forces; Integrate processes to improve efficiency
Raise System Mechanical/Electrical Efficiencies	Employ steam turbine drives for compression; Direct CO_2 liquefaction
OBJECTIVE 4 – Lower Specific Retrofit Costs	
Process Synthesis	Develop new "re-design" concepts for retrofits
Reduce Engineering, Design, Installation Costs	Develop standard/modular CCS retrofit packages
OBJECTIVE 5 – Increase Onsite Steam & Power Generation	
Supply CCS Parasitic Load with Waste Heat	Condensation of flue-gas water vapor
Increase Boiler Capacity	Firing with oxygen-enriched air may allow increased coal feed rates
Add Supplemental Boiler for Steam Generation	Produce steam required by CCS, possibly from alt. fuels such as natural gas, biomass, and wastes
Total CO_2 TSM Capital & Operating Costs – Outside of Purview of EPEC Program	

The list in Table 4 is in no way complete, and it is certain that future technology developments and further analysis will lead to new ideas and improved concepts.

Table 5 summarizes the impact the various strategies outlined in Table 4 could have on the components of the direct and indirect costs of CCS. Note that some approaches affect more than one component of the total cost, and in some cases result in both increases as well as decreases.

Table 5: Cost Implications EPEC Program R&D Strategies

Strategy	In-plant Capex	In-plant Opex	TSM	Retro-fit	Make-Up
OBJECTIVE 1 – Lower Specific Capital Costs of CCS					
Improve CCS Process Technologies	↓				
Develop Alternative Materials of Construction	↓				
Process Intensification	↓				
Reduce Equipment Volumes	↓				
OBJECTIVE 2 – Lower Specific Operating Costs of CCS					
New or Improved Solvents, Sorbents, Membranes		↓			
Improve CDR Operability & Reliability		↓			
OBJECTIVE 3 – Improve Energy Efficiency of CCS					
Reduce Sorbent/Solvent Regeneration Energy				↓	↓
Reduce CO_2 Capture Requirement	↓	↓	↓	↑	↓
Process Intensification & System Integration				↓	↓
Raise System Mechanical/Electrical Efficiencies				↑	↓
OBJECTIVE 4 – Lower Specific Retrofit Costs					
Process Synthesis				↓	
Reduce Engineering, Design, Installation Costs				↓	
OBJECTIVE 5 – Increase Onsite Steam & Power Generation					
Supply CDR Parasitic Load with Waste Heat				↑	↓
Increase Boiler Capacity	↑↓	↑↓	↑↓	↑	↓
Add Supplemental Boiler for Steam Generation	↑↓	↑↓	↑↓	↑	↓
Total CO_2 TSM Capital & Operating Costs – Outside of Purview of EPEC Program					

IV. RECOMMENDATIONS

EPEC Program R&D is focused on longer-term, higher-risk projects. Long-term R&D goals have been established for CCS technologies to be deployed on existing PC power plants in the future:

Minimum CO_2 Captured = 90%

Maximum Increase in COE = 35%

These goals are feasible, but aggressive, and may be achievable through a focused R&D program directed toward:

1) Lowering the direct capital and operating costs of in-plant CCS technology.
2) Improving the efficiency of CCS technology to minimize de-rating of existing PC power plants.
3) Increasing onsite steam and power generation to off-set CCS parasitic requirements.

In addition, lowering the costs associated with retrofitting existing PC plants with CCS will be needed to ensure that CO_2 capture R&D can be implemented at a level necessary to significantly impact climate change.

The above goals will be applied to existing and future DOE R&D projects related to PC power generation fitted with post-combustion CO_2 capture, oxy-combustion, or chemical looping technologies. The goals will be used to guide DOE-sponsored CO_2 capture R&D under the EPEC Program and to assess progress in any R&D efforts.

A number of new avenues for R&D are suggested. These include:

1) Development of hybrid systems able to simultaneously lower both the direct and indirect costs of capture.
2) Development of "process-intensified" unit operations to reduce both the CCS footprint and increase efficiency.
3) Use of oxygen-enriched air for combustion in existing plants, also to reduce footprint and increase efficiency.
4) Co-firing with low-carbon fuels, such as natural gas, biomass, or other waste materials, either in the existing boiler or in a new supplemental boiler.
5) Use of steam-turbine drives to improve the efficiency of CO_2 compression.

These concepts need to be further assessed to quantify potential cost and performance benefits, and to identify new R&D opportunities.

REFERENCES

1. Johnson, J., “Government & Policy,” *Chemical & Engineering News*, p.44, 02/23/09.
2. *Cost and Performance Baseline for Fossil Energy Plants—Volume 1: Bituminous Coal and Natural Gas to Electricity*, National Energy Technology Laboratory, DOE/NETL-2007/1281, Revision 1, August 2007.
3. *Carbon Dioxide Capture from Existing Coal-Fired Power Plants,* National Energy Technology Laboratory, DOE/NETL 401/110907, Revised Report, November 2007.

APPENDIX A – Economic Metrics for CCS

There are several "metrics" that can be defined for measuring the economic performance of CO_2 capture technologies that are applicable to both new and existing power plants. Four possible options are:

1) Incremental COE – additional electricity generation costs due to adding CO_2 capture, transport, and storage. Scalar is cost per electricity production unit ($/kWh, ¢/kWh, or mills/kWh).

$$Incremental\ COE = COE_{Capture} - COE_{NoCapture} \tag{A-1}$$

2) Percent increase in COE – percent increase in COE due to adding CO_2 capture, transport, and storage above that of the non-capture equivalent power plant.

$$\%Increase\ \ COE = \left(\frac{COE_{Capture} - COE_{NoCapture}}{COE_{NoCapture}} \right) \times 100 \tag{A-2}$$

3) Cost per ton of CO_2 captured (or removed) – cost specific to adding CO_2 capture, transport, and storage. It does not completely account for CO_2 capture energy penalty, because it does not account for CO_2 emitted during generation of parasitic power.

$$CO_2\ Capture\ Cost = \left(\frac{COE_{Capture} - COE_{NoCapture}}{CO_2 Captured} \right) \tag{A-3}$$

4) Cost per ton of CO_2 avoided – CO_2 avoided is the difference between the amount of CO_2 emitted by the plant without CO_2 capture and the CO_2 emitted by the plant with CO_2 capture (see Figure 1).

$$CO_2\ \ Avoided\ \ Cost = \left(\frac{COE_{Capture} - COE_{NoCapture}}{CO_2 Emissions_{NoCapture} - CO_2 Emissions_{Capture}} \right) \tag{A-4}$$

The incremental COE or percentage increase in COE may be the easiest concept to grasp. However, for policymakers and regulators, CO_2 capture cost in $/ton of CO_2 captured or avoided are alternative metrics that may have more meaning.

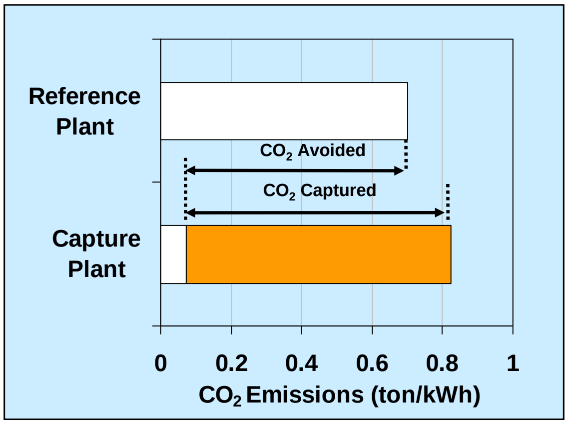

Figure A-1: Difference between "CO_2 Captured" and "CO_2 Avoided"

APPENDIX B – Baseline Power Plant Design

In order to establish a consistent baseline comparison, it was decided to compare each CO_2 capture technology as it would be applied to a consistent, yet conceptual plant design. NETL completed a report, titled, "Cost and Performance Baseline for Fossil Energy Plants," which established SOTA power generation technologies both with and without carbon capture. This report established the baseline design, operation, and economics of a subcritical PC power plant, which is considered to be the baseline for comparison of CCS (capture, transport, and storage) technologies evaluated by the EPEC Program. Establishing a consistent, unbiased baseline for comparison allows NETL evaluation of CCS technologies to occur without the influence of the eccentricities of existing power plants that may otherwise be selected as a baseline; incorporating certain CCS technologies in unique plant configurations, locations, etc., may result in more attractive, niche-type, applications than might be the case if the same technology was proposed as a fleet-wide solution to CO_2 emissions.

In addition, it was decided to conceptually apply any proposed post-combustion CO_2 capture technology to a plant that would result in the same net power output as the baseline power plant without capture. Typically, when CCS technology is implemented, a significant auxiliary load is required to perform the CO_2 capture and sequestration. This means that the existing power plant grid will lose power generation capacity. It is difficult to quantify the effect of this lost power simply because there are so many options to replenish this power. Because this is difficult, and fortunately not required to adequately compare one post-combustion CCS technology to another, it is outside the scope of the EPEC goal structure to account for making up any lost power due to CCS implementation; the purpose of this document is to simply explain and justify the EPEC goals for post-combustion CCS R&D and how to compare the technical and economic performance of different CCS technologies against these goals. For the purposes of evaluating post-combustion CCS technologies against the EPEC goals, it was proposed to compare all post-combustion CCS technologies as installed on a plant that has a net 550 MW capacity to a baseline plant without capture that has a net 550 MW capacity. Essentially, this evaluation process demands that all post-combustion CCS technologies make up power in the same way – by increasing plant size. While it is a theoretical evaluation, this process allows the post-combustion CCS evaluation to avoid the cost consideration of the many ways to make up the lost power to the grid.

The baseline plant to be used for post-combustion CCS technology evaluation is described in more detail in the following sections.

Table B-1: Plant Performance Summary

Plant type	PC Subcritical
Carbon capture	No
Net power output (kWe)	550,445
Net plant HHV efficiency (%)	36.8%
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ **85% capacity factor**	64.0
Total plant post ($ x 1,000)	$852,612

Plant Overview

The base plant is a 550-MWe (net power output) subcritical bituminous PC plant located at a greenfield site in the midwestern United States. This plant is designed to meet Best Available Control Technology (BACT) emission limits. The plant is a single-train design. The combination process, heat, and mass balance diagram for the subcritical PC plant is shown in Figure B-1. The primary fuel is an Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. The capacity factor (CF) for the plant is 85 percent without sparing of major train components. A summary of plant performance data for the subcritical PC plant is presented in Table B-1.

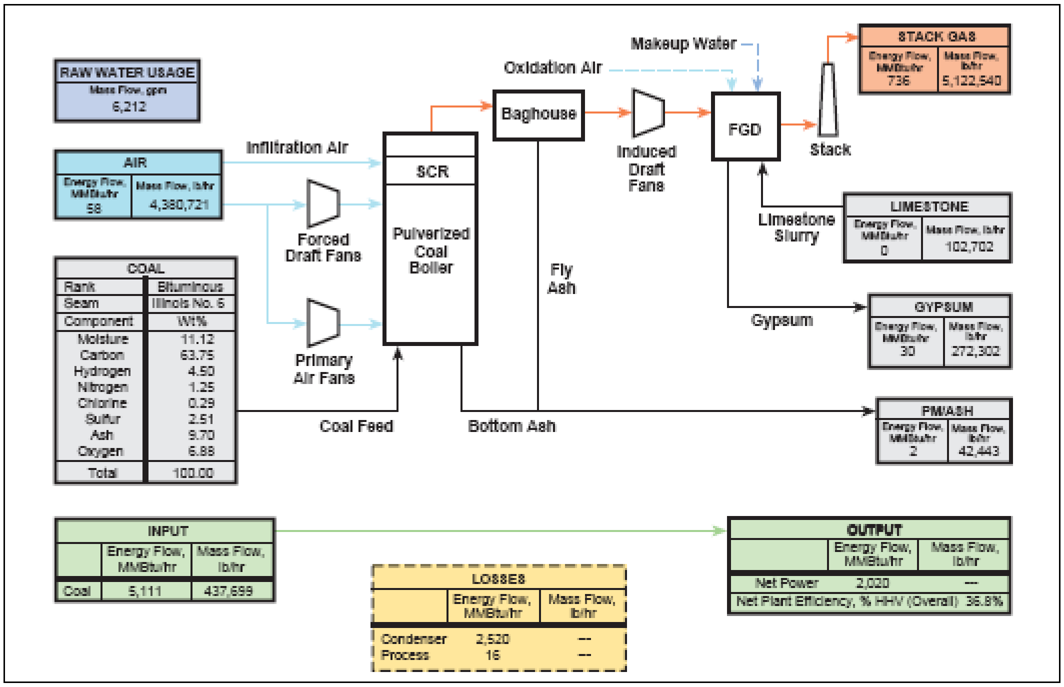

Figure B-1: Process Flow Diagram
Subcritical Pulverized Coal Unit

Technical Description

The analysis for the subcritical PC plant is based on a commercially available dry-bottom, wall-fired boiler equipped with low-nitrogen oxides burners (LNBs) and over-fire air (OFA). The unit is a balanced-draft, natural-circulation design equipped with a superheater, reheater, economizer, and air preheater. Hot flue gas exiting the boiler is treated by a selective catalytic reduction (SCR) unit for nitrogen oxides (NOx) removal, a baghouse for particulate matter (PM) removal, and a limestone-based scrubber for sulfur dioxide (SO_2) control and co-removal of mercury (Hg). This plant utilizes a conventional steam turbine for power generation. The Rankine cycle is based on a single reheat system with steam conditions of 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F).

Achieving a nominal 550 MWe net output with this plant configuration results in a HHV thermal input requirement of 1,496,479 kWt (5,106 MMBtu/hr basis). This thermal input is achieved by burning coal at a rate of 437,699 lb/hr, which yields an HHV net plant heat rate of 9,276 Btu/kWh (a net plant efficiency of 36.8 percent). The gross power output of 583 MWe is produced from the steam turbine generator. With an auxiliary power requirement of 33 MWe, the net plant output is 550 MWe.

Environmental Performance

This study assumes the use of BACT to meet the emission requirements of the 2006 New Source Performance Standards.

The subcritical PC plant emission control strategy consists of a wet-limestone, forced-oxidation scrubber that achieves a 98 percent removal of SO_2. The byproduct, calcium sulfate, is dewatered and stored onsite. The wallboard-grade material potentially can be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit is taken. The combination of SCR, a fabric filter, and wet scrubber also provides co-benefit. Mercury capture is assumed at 90 percent of the inlet value. The saturated flue gas exiting the scrubber is vented through the plant stack. NOx emissions are controlled through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent. Particulate emissions are controlled using a pulse jet fabric filter that operates at an efficiency of 99.8 percent.

Table B-2: Air Emissions Summary @ 85% Capacity Factor

Pollutant	PC Subcritical Without CCS
CO_2	
• **tons/year**	3,864,884
• **lb/MMBtu**	203
• **cost of CO_2 avoided ($/ton)**	N/A
SO_2	
• **tons/year**	1,613
• **lb/MMBtu**	0.085
NOx	
• **tons/year**	1,331
• **lb/MMBtu**	0.070
PM (filterable)	
• **tons/year**	247
• **lb/MMBtu**	0.013
Hg	
• **tons/year**	0.022
• **lb/TBtu**	1.14

A summary of the resulting air emissions is presented in Table B-2.

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date are used to develop capital cost, production cost, and levelized cost of electricity (LCOE) estimates. Costs for the plant are based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table B-3.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 11.2 percent of the subcritical PC case without CCS TPC.

No process contingency is included in this case because all elements of the technology are commercially proven.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 85 percent for PC cases.

The 550-MWe (net) subcritical PC plant is projected to have a TPC of $1,549/kWe, resulting in a 20-year LCOE of 64.0 mills/kWh.

MAJOR ASSUMPTIONS						
Case:	1x550 MWe net subcritical_PC					
Plant Size:	550.4	(MWe, net)	Heat Rate:	9,276	(Btu/kWh)	
Primary/Secondary Fuel (type):	Illinois #6		Cost:	1.804	($/MMBtu)	
Design/Construction:	3	(years)	Book Life:	20	(years)	
Total Plant Cost[2] Year:	2007	(Jan)	Plant in Service	2010	(January)	
Capacity Factor:	85	(%)	Capital Charge Factor	16.4	(%)	
RESULTING CAPITAL INVESTMENT (2007 dollars)						**Mills/kWh**
TOTAL PLANT COST						34.1
RESULTING OPERATING COSTS (2007 dollars)						**Mills/kWh**
FIXED OPERATING COST						3.8
						Mills/kWh
VARIABLE OPERATING COST						5.8
						Mills/kWh
RESULTING FUEL COST (2007 dollars) @	$1.804 / 10^6 Btu					20.2
						Mills/kWh
TOTAL LEVELIZED BUSBAR COST OF POWER (2007 dollars)						64.0

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owners costs are not included.

[3]No credit taken for by-product sales.

APPENDIX C – Reallocation of CCS Costs

In 2007, NETL completed an extensive systems analysis of current SOTA fossil energy-based power plants that included IGCC, PC, and Natural Gas Combined Cycle (NGCC) plants [2]. The objective of the study was to present performance and cost estimates for *new* power systems using a consistent technical and economic framework that accurately reflected current market conditions for plants starting construction in a 2010 timeframe. A major focus of the 2007 study was to assess the impact CO_2 capture, transport and storage will have on the performance and COE for type of each power plant. The development of a COE goal for improved CO_2 capture technologies, applicable to existing power plants, begins with the cost of current SOTA post-combustion CO_2 capture technology employing amine-based scrubbing.

A. Cost Distribution for CCS from Subcritical PC Baseline Study

Table C-1 summarizes the 2007 results for *new* PC plants. These subcritical PC plant designs, with and without 90 percent CO_2 capture (Cases 9 and 10, respectively [2]), are a useful starting point for establishing post-combustion CO_2 capture goals for existing PC power plant retrofits. These cases are based upon bituminous coal, a generic U.S. plant site, and CO_2 pressurized to 2,200 psia, transported via pipeline 50 miles and stored in a saline geological formation.

Table C-2 lists the COE breakdown for the new subcritical PC power plant without capture and compression (the Reference Plant) and the incremental COE for the same plant fitted with CO_2 capture and compression. The total COE of the reference power plant is 64 mills/kWh, and the incremental COE for the same plant with CCS is 54.8 mills/kWh. These costs are allocated to five categories: capital; fuel; fixed operating expenses; variable operating expenses (excluding fuel); and CO_2 TSM. It appears that capital cost is the largest contribution to incremental COE. However, this is somewhat misleading since CO_2 capture and compression consumes a large amount of parasitic power (direct electricity requirements and indirectly as steam consumption) that should be allocated to the cost of CCS.

Due to parasitic power requirements, the PC plant fitted with CO_2 capture and compression must be larger than the Reference Plant to maintain a 550 MW net output. Increased plant capacity is needed to provide the electricity (included in auxiliary power) and low-pressure stream (extracted from the steam turbine) required for CO_2 capture and compression[g]. The capital cost increase (33.9 mills/kWh) given in Table C-2 in effect includes, but does not explicitly break out, the energy-related capital cost of CO_2 capture and compression and TSM due to the additional costs for increased plant capacity (i.e., larger boiler, larger steam turbine, etc.) required for make-up power. This same argument applies to fixed (*e.g.*, increased maintenance requirements) and variable (*e.g.*, increased consumables) operating costs, and fuel cost (*e.g.*, increased coal consumption).

[g] The bulk of the electricity is used in compression and the steam in the amine regeneration step.

Table C-1: 2007 NETL Baseline Study Summary
a) *Subcritical PC Power-Plant Design*

	Case 9 no CO_2 Capture	Case 10 w/CO_2 Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2400/1050/1050)	16.5/566/566 (2400/1050/1050)
Coal	Illinois No. 6	Illinois No. 6
Boiler Efficiency	89%	89%
TOTAL AUXILIARIES, kWe	32,870	130,310
NET POWER, kWe	550,445	549,613
Net Plant Efficiency (HHV)	36.8%	24.9%
Net Plant Heat Rate (Btu/kWh)	9,276	13,724
Thermal Input, kWt	1,496,479	2,210,668
Stack Temperature, °C (°F)	57 (135)	32 (89)
SO_2 Control	Wet Limestone Forced Oxidation	Wet Limestone Forced Oxidation
FGD Efficiency[a]	98%	98%[b,c]
NOx Control	LNB w/OFA and SCR	LNB w/OFA and SCR
SCR Efficiency[a]	86%	86%
Ammonia Slip (end of catalyst life)**, ppmv**	2	2
Particulate Control	Fabric Filter	Fabric Filter
Fabric Filter Efficiency[a]	99.8%	99.8%
Ash Distribution, Fly/Bottom	80% / 20%	80% / 20%
Hg Control	Co-benefit Capture	Co-benefit Capture
Hg Removal Efficiency[a]	90%	90%
CO_2 Control	N/A	Econamine FG+™
CO_2 Capture[a]	N/A	90%
CO_2 Sequestration	N/A	Offsite Saline Formation

[a]Removal efficiencies are based on the flue gas content.
[b]An SO_2 polishing step is included to meet more stringent SOx content limits in the flue gas (<10 ppmv) to reduce formation of amine heat stable salts during the CO_2 absorption process.
[c]SO_2 exiting the post-FGD polishing step is absorbed in the CO_2 capture process making stack emissions negligible.

Table C-2: 2007 NETL Baseline-Study Summary
b) *Cost of Electricity Breakdown*

Cost of Electricity (COE) →		No Capture (mills/kWh)	CO_2 Capture (mills/kWh)	Incremental (mills/kWh)
	Capital	34.1	68.0	34.
Operating	Fixed Operating	3.8	5.8	2.0
	Variable Operating	5.8	10.8	5.0
	Fuel	20.2	29.8	9.6
	CO_2 TSM	0	4.3	4.3
	Total (mills/kWh)	**64**	**119**	**55**
	Percent Increase in COE		**86%**	

Allocation of the increase in COE to the components that make up the CCS system should accurately reflect the true causes of the increase. Such an allocation is valuable for establishing a realistic COE goal and for strategic program R&D planning to identify the most effective technologies and projects. Specifically, the increase in COE can be broken down into the five major categories to better reflect the true component costs:

1) Capital costs directly associated with CO_2 capture and pressurization.
2) Operating costs directly associated with CO_2 capture and pressurization.
3) Capital and operating costs directly associated with CO_2 TSM.
4) Indirect capital and operating costs associated with retrofitting the existing plant to accept the CO_2 capture and compression system.
5) Indirect costs of make-up power associated with de-rating the existing plant.

The first three items above are directly associated with the addition and operation of the CO_2 capture and compression and TSM systems for the retrofitted plant. The last two items are indirect consequences of adding CO_2 capture and compression and TSM systems to the existing plant.

For a grassroots plant engineered and designed for CCS, the retrofit costs would be zero. Ideally, the cost of the retrofit would be small, on the order of 20 percent or less of the capital cost of the CO_2 capture and compression. It would include incidental costs associated with installing the CO_2 capture and compression on the existing plant, such as wiring and piping rerouting and tie-ins, plant layout modifications, etc. In reality, retrofitting costs are likely to be quite large, 50 percent of the CO_2 capture and compression capital or possibly much more, due to modifications to the operation of the existing boiler and steam turbine, which could be required if the CO_2 capture and compression system consumes large quantities of steam. However, the make-up power costs are the same for a plant retrofitted with CO_2 capture and compression and a new plant of the same capacity employing the same CO_2 capture and compression technology. The difference between the two is that for the retrofit, the make-up power is supplied to the grid by some unidentified source outside the plant fence; whereas, the new plant is oversized in order to supply the power deficit caused by the operation of the CO_2 capture and compression and TSM systems.

Some long-term retrofit options may have high direct capture costs and low indirect capture costs, and vise versa. This is analogous to the tradeoff that often exists between capital and operating costs for most industrial processes. If the make-up power cost is high, then the direct capital and operating costs will need to be low, and vice versa.

The re-distribution described above has been applied to the subcritical PC power plant as described in detail below.

B. Reallocation of CCS Costs for Existing PC Plant

Table C-3 compares the capital breakdown of a new subcritical PC plant with and without 90 percent CO_2 capture. The total capital cost of the CO_2 capture process is $792/kW, which contributes approximately18.6 mills/kWh to COE. However, the CO_2 capture and compression facility not only removes 90 percent of the CO_2 emissions from the Reference Plant, but also removes 90 percent of the CO_2 emission resulting from the increased capacity required to produce the extra power (and steam) required by the CO_2 capture and compression facility and CO_2 TSM; that is, the additional CO_2 emissions related to the CO_2 capture facility parasitic load. If the CO_2 capture and compression process did not consume any steam or electricity, the size of the power island with CO_2 capture would be the same size as that of the Reference Plant.

Table C-3: Capital Cost of New Subcritical PC Plant With and Without CO_2 Capture
Nominal 550 MW Capacity

Item/Description	Total Plant Cost ($/kW)		Capital Cost of Electricity (mills/kWh)		
	Reference	With Capture	Reference	With Capture	Incremental
Coal Handling	69	88	1.52	2.07	0.55
Coal Preparation & Feeding	32	42	0.70	0.99	0.28
Feed water & Misc. BOP Systems	128	183	2.82	4.30	1.48
Boiler (including NOx Control)	461	606	10.15	14.23	4.09
Flue Gas Cleanup (PM & SOx)	246	323	5.42	7.59	2.17
CO_2 Capture System		**792**		**18.60**	**18.60**
CO_2 Compression & Drying		**89**		**2.09**	**2.09**
Total CDR Cost →		**→ 881**		**20.69**	**→ 20.70**
Ducting & Stack	68	76	1.50	1.79	0.29
Steam Turbine Generator	197	228	4.34	5.36	1.02
Cooling Water System	68	119	1.50	2.80	1.30
Ash Handling	23	28	0.51	0.66	0.15
Accessory Electric Plant	88	139	1.94	3.26	1.33
Instrumentation & Control	37	44	0.81	1.03	0.22
Site improvements	24	28	0.53	0.66	0.13
Buildings & Structures	108	111	2.38	2.61	0.23
Total Plant Cost →	**$1,549**	**$2,895**	**34.**	**68.**	**34.**

The Reference Plant has a net output of 550.4 MWe and a net thermal efficiency of 36.8 percent. Therefore, the Reference Plant heat input is:

$$HeatInput_{NoCapture} = \left(\frac{550.4MW}{0.368} \right) = 1{,}496\, MW_{th} \tag{C-1}$$

For the plant with capture, the net output is 549.6 MWe, but the net thermal efficiency is reduced to 24.9 percent, and the plant heat input is:

$$HeatInput_{Capture} = \left(\frac{549.6MW}{0.249} \right) = 2{,}207\, MW_{th} \tag{C-2}$$

The incremental heat input, equal to 2,207-1,496 = 711 MWth, is directly consumed by the capture and compression facility, and the increase in auxiliary load for the rest of the plant caused by the increase in coal throughput. The lost electrical power production from the increase in heat input can be estimated based on the thermal efficiency of the Reference Plant:

$$CO_2 Cap \,\&\, Comp_{Electricity\ Equivalent} = 711 \times .368 = 262\, MWe \tag{C-3}$$

Therefore, the CO_2 capture and compression process is capturing the CO_2 emissions from a power plant equivalent to one with a net output of 550+262 = 812 MWe. This increased capacity requires the CO_2 capture and compression facility to be larger. Clearly, this scale up is caused by the energy penalty associated with operating the CO_2 capture and compression and should be considered as part of the cost of make-up power. The approximate incremental capital cost of capturing 90 percent of the Reference Plant CO_2 emissions can be estimated (ignoring economies of scale for simplification) as:

$$Capture_{Capital} = \left(\frac{18.6 mills / kWh}{812\, MWe} \right) \times 550\, MWe = 12.6 (mills / kWh) \tag{C-4}$$

The remaining 18.6-12.6 = 6 mills/kWh is a component of the make-up cost.

Likewise, the incremental cost of CO_2 compression, fixed and variable operating costs for CO_2 capture and compression, and TSM costs can be distributed between the direct and indirect costs of CCS:

$$Compression_{Capital} = \left(\frac{2.09 mills / kWh}{812\, MWe} \right) \times 550\, MWe = 1.4 (mills / kWh) \tag{C-5}$$

$$CO_2 Cap \,\&\, Comp_{Fixed} = \left(\frac{2 mills / kWh}{812\, MWe} \right) \times 550\, MWe = 1.4 (mills / kWh) \tag{C-6}$$

$$CO_2 Cap \,\&\, Comp_{Variable} = \left(\frac{5 mills / kWh}{812\, MWe} \right) \times 550\, MWe = 3.4 (mills / kWh) \tag{C-7}$$

$$TSM_{Total} = \left(\frac{4.3 mills / kWh}{812\,MWe} \right) \times 550\,MWe = 2.9 (mills / kWh) \qquad \text{(C-8)}$$

Finally, using the reallocated costs above, the cost of make-up power is calculated using[h]:

$$\begin{aligned} CCS_{Total} &= Capture_{Capital} + Compression_{Capital} + CDR_{Fixed} \\ &+ CDR_{Variable} + TSM_{Total} + CCS_{Make-UpPower} \end{aligned} \qquad \text{(C-9)}$$

Therefore: ***CCS*** ***Make-Up Power*** **= 55 – 12.6 – 1.4 – 1.4 – 3.4 – 2.9 = 33 (mills/kWh).** Note that fixed and variable costs do not scale linearly as was assumed for simplicity above; however, the overall error introduced by using this assumption will be small and will be ignored.

The redistributed costs of four categories of interest are listed in Table C-4. Clearly, capture energy and capture capital costs are two major components for CCS.

Table C-4: Redistributed CO_2 Capture & Sequestration Costs

CCS Specific Costs	Incremental COE (mills/kWh)	Percent of Total
CO_2 Capture Direct Capital	12.6	23.0%
CO_2 Compression Direct Capital	1.4	2.6%
Direct Fixed Operating	1.4	2.6%
Direct Variable Operating	3.4	6.2%
Total In-Plant Direct	**18.8**	**34.3%**
Total CO_2 TSM Direct	**2.9**	**5.3%**
TOTAL CCS Direct Costs	**21.7**	**39.6%**
Total Retrofit*	**-**	**-**
Make-Up Power	**33.1**	**60.4%**
TOTAL CCS Indirect Costs	**33.1**	**60.4%**
TOTAL CCS Costs	**54.8**	**100%**

*Retrofit costs will vary based on CO_2 capture and compression technology deployed and existing plant specifics.

[h] It is not necessary for this analysis to determine the distribution of costs for the make-up power. However, it is of interest to note that the additional coal costs 9.6 mills/kWh, accounts for almost 30% of the make-up power cost.

In summary, for post-combustion CO_2 capture using SOTA amine-based scrubbing technology:

- **Net efficiency is reduced by 33 percent (12 net efficiency points).**
- **COE increases to 55 mills/kWh (86 percent increase).**
- **Of the increase in COE, 60 percent is due to costs associated with capture-related parasitic power, i.e., the "Energy Penalty."**
- **Only 25 percent of the increase in COE is due to costs directly associated with CO_2 capture and compression.**
- **Costs for retrofitting CO_2 capture and compression technology to an existing PC power plant are highly variable and may be as low as 20 percent or as high as 50 percent and possibly even higher.**

APPENDIX D – Thermodynamic Analysis of CCS

The minimum energy of CO_2 separation can be deduced according to the first and second law of thermodynamics. Consider the following steady state flow system (also assuming that the kinetic and potential energy terms are negligible):

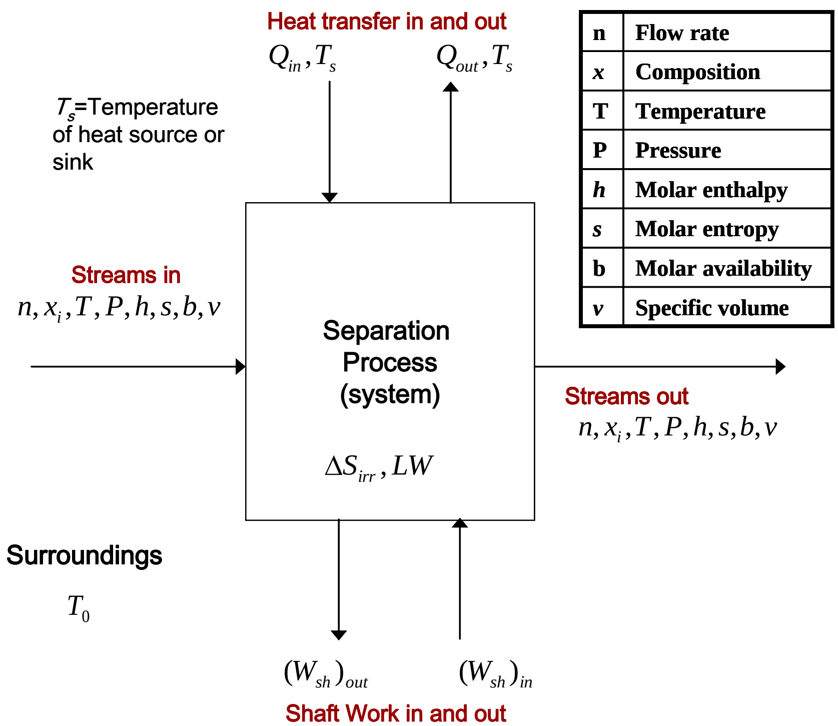

Figure D-1: Schematic of a Steady State Flow System

The first law of thermodynamics requires that:

(Stream enthalpy flow + heat transfer + shaft work) $_{\text{leaving system}}$
- (Stream enthalpy flow + heat transfer + shaft work) $_{\text{entering system}}$ = 0

Or mathematically:

$$\sum_{\text{out of system}} (nh + Q + W_{sh}) - \sum_{\text{into system}} (nh + Q + W_{sh}) = 0 \qquad \text{(D-1)}$$

And the second law of thermodynamics requires that:

(Stream entropy flow + entropy flow by heat transfer) $_{\text{leaving system}}$
- (Stream entropy flow + entropy flow by heat transfer) $_{\text{entering system}}$
= Production of entropy by the process

Or it can be expressed as:

$$\sum_{\text{out of system}} (ns + \frac{Q}{T_s}) - \sum_{\text{in to system}} (ns + \frac{Q}{T_s}) = \Delta S_{irr} \quad \text{(D-2)}$$

Here, ΔS_{irr} is a measure of the energy inefficiency of the process, the greater the value of ΔS_{irr}, the more inefficient of the process.

The availability (Exergy) balance of the system is:

$$\sum_{\text{in to system}} (nb + Q(1 - \frac{T_0}{T_S}) + W_{sh}) - \sum_{\text{out of system}} (nb + Q(1 - \frac{T_0}{T_S}) + W_{sh}) = LW \quad \text{(D-3)}$$

Here "b" is the molar availability of the stream and is defined as:

$$b = h - T_0 s = \sum x_i \cdot h_i(T) - T_0 \left[\sum x_i \cdot s_i(T) + R \sum x_i \cdot \ln(\frac{1}{x_i}) \right] \quad \text{(D-4)}$$

And LW is the lost work of the process, which is defined:

$$LW = T_0 \Delta S_{irr} \quad \text{(D-5)}$$

The minimum work required can be achieved when the inefficiency loss of the separation process LW is zero, that is, the separation process is reversible. Under such circumstance equation (D-3) can be rearranged into:

$$W_{\min} = \sum_{\text{into system}} nb - \sum_{\text{out of system}} nb \quad \text{(D-6)}$$

Equation (D-3) is now applied to the flue gas CO_2 separation system. For simplicity, the flue gas is assumed to be an ideal gas mixture and it has only two components (N_2 and CO_2). The mole fractions of the flue gas components are x_{CO2} for CO_2 and $1-x_{CO2}$ for N_2, respectively. Further, the required recovery rate for CO_2 is θ and the product CO_2 is 100 percent pure is assumed. Figure D-2 is the schematic diagram of the separation process.

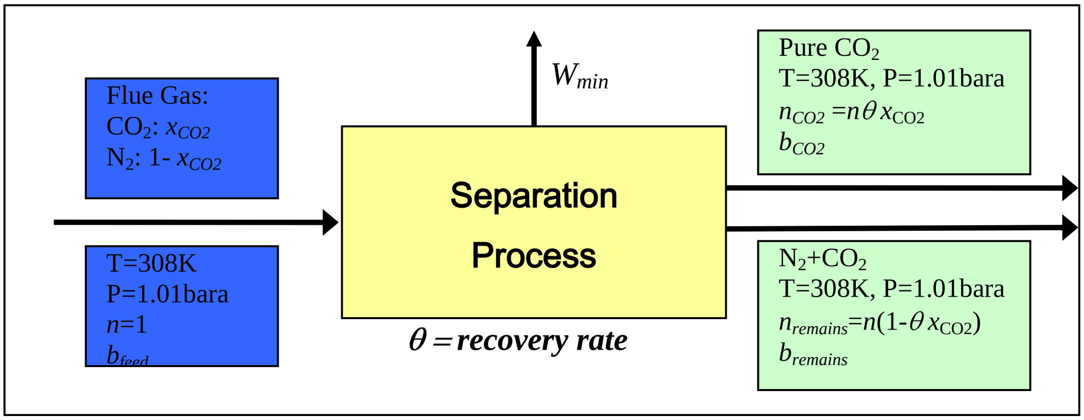

Figure D-2: Schematic Diagram of CO_2 Separation from Flue Gas

Under the above assumptions and the conditions shown in Figure D-2, each term in equation (D-6) can be calculated as follows.

The molar availability of the feed stream is:

$$b_{feed} = h - T_0 s = \sum x_i \cdot h_i(T) - T_0\left[\sum x_i \cdot s_i(T) + R\sum x_i \cdot \ln(\frac{1}{x_i})\right]$$

$$b_{feed} = x_{CO2}h_{CO2} + (1-x_{CO2})h_{N2} - T_0\left[x_{CO2}s_{CO2} + (1-x_{CO2})s_{N2} + R\left\{x_{CO2}\ln\frac{1}{x_{CO2}} + (1-x_{CO2})\ln\frac{1}{(1-x_{CO2})}\right\}\right] \quad \text{(D-7)}$$

The molar availability of pure CO_2 stream is:

$$b_{CO2} = h - T_0 s = h_{CO2} - T_0 s_{CO2} \quad \text{(D-8)}$$

And the molar availability of the remaining flue gas is:

$$b_{remains} = h - T_0 s = \sum x_i \cdot h_i(T) - T_0\left[\sum x_i \cdot s_i(T) + R\sum x_i \cdot \ln(\frac{1}{x_i})\right]$$

$$b_{remains} = \frac{(1-\theta)\,x_{CO2}}{1-\theta\, x_{CO2}}h_{CO2} + \frac{(1-x_{CO2})}{1-\theta\, x_{CO2}}h_{N2} - T_0\left[\begin{array}{l}\frac{(1-\theta)\,x_{CO2}}{1-\theta\, x_{CO2}}s_{CO2} + \frac{(1-x_{CO2})}{1-\theta\, x_{CO2}}s_{N2} + \\ R\left\{\frac{(1-\theta)\,x_{CO2}}{1-\theta\, x_{CO2}}\ln\frac{1-\theta\, x_{CO2}}{(1-\theta)\,x_{CO2}} + \frac{(1-x_{CO2})}{1-\theta\, x_{CO2}}\ln\frac{1-\theta\, x_{CO2}}{(1-x_{CO2})}\right\}\end{array}\right] \quad \text{(D-9)}$$

The minimum work of the separation system in terms of per mole of feedstock is:

$$W_{\min} = \sum_{\text{into system}} b - \sum_{\text{out of system}} b = b_{in} - \theta\, x_{CO2}b_{co2} - (1-\theta\, x_{CO2})b_{remains}$$
$$W_{\min} = Eq.(D7) - \theta\, x_{CO2}Eq.(D8) - (1-\theta\, x_{CO2})Eq.(D9) \quad \text{(D-10)}$$

Through mathematical manipulations, Equation (D-10) can be simplified to:

$$W_{\min} = -RT_0\left(x_{CO2}\ln(\frac{1}{x_{CO2}}) + (1-\theta\, x_{CO2})\ln\left(\frac{1}{(1-\theta\, x_{CO2})}\right) + (1-\theta)x_{CO2}\ln((1-\theta)x_{CO2})\right) \quad \text{(D-11)}$$

And the minimum work in terms of per mole of CO_2 captured is:

$$W_{\min} = -\frac{RT_0}{\theta}\left(\ln(\frac{1}{x_{CO2}}) + \frac{(1-\theta\, x_{CO2})}{x_{CO2}}\ln\left(\frac{1}{(1-\theta\, x_{CO2})}\right) + (1-\theta)\ln((1-\theta)x_{CO2})\right) \quad \text{(D-12)}$$

Using equation (D-12), the minimum work required to recover θ of the CO_2 with 100 percent purity can be calculated. At θ = 90 percent the minimum work is -7.68 kJ/moleCO_2 or -175 kJ/kgCO_2. The negative value indicates input of work to the process is required. Since practical CO_2 separations are carried out at around 40°C (308 K), 308 K is used for T_0, instead of 298 K in this calculation.

The pressure of the separated CO_2 in the above calculation (Figure D-2) is 1.01 bars. However, for pipeline transportation, CO_2 must be compressed to 150 atmospheric pressures (about 2,200 psia), that is the separated CO_2 needs to be further compressed.

The minimum compression work, W_c, required to compress CO_2 to 2,200 psia can be calculated using the following equation:

$$W_c^{\min} = \int_{1atm}^{150(2200\,psi)} Pdv \approx 11.6(kJ/molCO_2) = 265(kJ/kgCO_2) \qquad \text{(D-13)}$$

In integrating Equation (D-13), the van der Waals equation-of-state was used (other equations-of-state can also be used). Based on Equation (D-13), the minimum work required to compress CO_2 from 1 atm and 308 K to a pipeline pressure of 2,200 psia is 265 kJ/kg of CO_2 (113.6 Btu/lb).

Therefore, the total minimum energy required for capturing 90 percent of the CO_2 from a post-combustion flue gas and compressing it to 2,200 psia is:

$$W_{CCS}^{\min} = 175\,\text{kJ/kgCO}_2 + 265\,\text{kJ/kgCO}_2 = 440\ \text{kJ/kgCO}_2 = 188\,BTU/lbCO_2 \qquad \text{(D-14)}$$

The separation energy consumption for the current SOTA amine process can be obtained from the NETL Baseline Report which is 1,506 kJ/kgCO_2. The current efficiency of the amine process is:

$$Efficiency = 440/1506 = 29.2\% \qquad \text{(D-15)}$$

Obviously, the efficiency of current SOTA amine process is still low with significant room to improve. For the EPEC program goal, a 60 percent reduction in energy consumption was assumed. If achieved through new separation technology development, the efficiency of the separation process will be:

$$Efficiency = 440/\{(1-0.6)\times 1506\} = 73\% \qquad \text{(D-16)}$$

Efficiency of 73 percent is high for a separation process, but is theoretically possible.